ATTACHMENT G: CONSTRUCTION DETAILS
CLEAN ENERGY SYSTEMS MENDOTA

1. Facility Information

Facility name:	CLEAN ENERGY SYSTEMS MENDOTA_INJ_1
Facility contact:	Rebecca Hollis 400 Guillen Pkwy, Mendota, CA 93640 Office: 916-638-7967
Well location:	MENDOTA, FRESNO COUNTY, CA LAT/LONG COORDINATES (36.75585015/-120.36440423)

2. Introduction

The testing activities at the Mendota INJ_1 described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in Attachment C, along with other non-well related pre-injection baseline activities such as geochemical monitoring.

This attachment is one of the several documents listed below that was prepared by Schlumberger and delivered to Clean Energy Systems. These documents were prepared to support the Clean Energy Systems preconstruction application to the EPA.

- (Schlumberger, Attachment A: Summary of Requirements Class VI Operating, 2020)
- (Schlumberger, Attachment B: Area of Review and Corrective Action Plan, 2020)
- (Schlumberger, Attachment C: Testing and Monitoring Plan, 2020)
- (Schlumberger, Attachment D: Injection Well Plugging Plan, 2020)
- (Schlumberger, Attachment E: Post-Injection Site Care and Site Closure Plan, 2020)
- (Schlumberger, Attachment F: Emergency and Remedial Response Plan, 2020)
- (Schlumberger, Attachment G: Construction Details Clean Energy Systems Mendota, 2020)
- (Schlumberger, Attachment H: Financial Assurance Demonstration, 2020)
- (Schlumberger, Class VI Permit Application Narrative, 2020)
- (Schlumberger Quality Assurance and Surveillance Plan, 2020)

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3. Injection Well Construction Details (Mendota_INJ_1)

A well construction diagram for the Mendota_INJ_1 injection well is shown below in Figure 1; Well construction details are presented in Table 1, Table 2, Table 3 and Table 4.

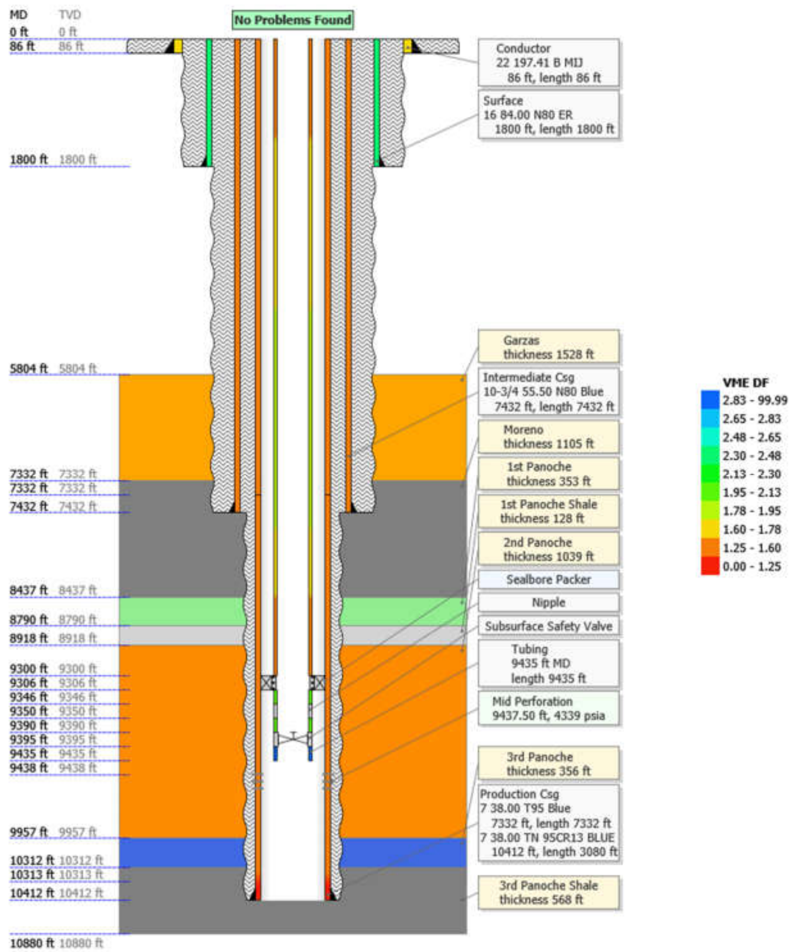

Figure 1: Injection Well Construction Diagram (Mendota_INJ_1)

Table 1: Open Hole Diameters and Intervals

Name	Depth Interval (feet)	Open Hole Diameter (inches)	Comment
Conductor	86	26	Will try to drive conductor (reason for 1" wall thickness) but need to get soil samples to determine if viable if not viable will drill 26 in hole
Surface	1800	20	1800 ft will cover any potential freshwater aquifers and provide sufficient kick tolerance for the intermediate string. Length may vary slightly in locating a formation with sufficient strength to provide a competent casing shoe.
Intermediate	8387	14.75	This string will be set 100 ft in the Moreno shale at 7432 ft.
Long-string	10412	9.625	Will drill across the 1st, 2nd and 3rd Panoche sands and have casing shoe below the 3rd Panoche Shale but may be set higher in the 3rd Panoche Sand if a suitable formation is found to set casing.

Table 2: Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	86	22	21	197.41	B	Welded	26.13	2440	1950
Surface	1800	16	15.01	84	N80	Long	26.13	4330	1480
Intermediate	7432	10.75	9.760	55.5	N80	Long	26.13	6450	4020
Long-string	7332	7	5.920	38	T-95 Type 1	Long	26.13	12830	13430
Long-string	10412	7	5.920	38	TN 95Cr13	Long	14.92	12830	13430

Table 3:Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	9430	3.5	2.992	9.2	L80Cr13	Long	10160	10540

Table 4: Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Seal Bore Packer in Super 13Cr	9300	64	38	5.685	4.0

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
133.12@250degF	5000	5000	6000	5.949

4. Pre-Injection Testing Plan – Injection Well

The following tests and logs will be conducted during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The tests and procedures are described below and in the Proposed Injection Well Construction Information section of the permit application.

4.1 Deviation Checks

Deviation measurements will be conducted at a minimum of approximately every 300 feet during construction of the well. More comprehensive deviation checks will be provided at the end of each hole section with greater granularity of 100 ft between checks with inclination and azimuth. (Note: This may be done with MWD while drilling the hole section). A gyro survey of the completed well will be done at the installation of the long string of casing for a final verification of the wellbore trajectory.

4.2 Tests and Logs

<u>*Surface*</u>

3D Seismic covering AoR

<u>*Surface section of wellbore*</u>

- Triple-combo (Density, Neutron Porosity, Resistivity, Gamma Ray, Spontaneous Potential)
- BHC Sonic

Pressure, temperature, fluid samples (USDW)
- Formation tester (MDT)

<u>*Intermediate section of wellbore*</u>

Porosity, permeability and lithology for future monitoring
- Triple-combo (Density, Neutron Porosity, Resistivity, Gamma Ray, Spontaneous Potential)
- Magnetic Resonance (CMR), Elemental Spectroscopy (LithoScanner), Spectral GR

Fractures, Geomechanics, Geophysical tie, Microseismic
- Borehole Imaging[1] (FMI)
- Dipole Sonic (Sonic Scanner – Anisotropy[1], Stoneley[1])

Pressures, permeability, fluid samples, Calibrate geomechanics/formation stress
- Formation tester (MDT)
- Dual Packer or Sleeve DFIT tests (MDT)

Core
- Whole core[1]
- Mechanical Sidewall Cores (depending on core results)

<u>*TD section of wellbore*</u>

Porosity, permeability and lithology for future monitoring
- Triple-combo (Density, Neutron Porosity, Resistivity, Gamma Ray, Spontaneous Potential)
- Magnetic Resonance (CMR), Elemental Spectroscopy (LithoScanner), Spectral GR

Fractures, Geomechanics, Geophysical tie, Microseismic
- Borehole Imaging[1] (FMI)
- Dipole Sonic (Sonic Scanner – Anisotropy[1], Stoneley[1])

Pressures, permeability, fluid samples, Calibrate geomechanics/formation stress
- Formation tester (MDT)
- Dual Packer or Sleeve DFIT tests (MDT)

Geophysical

- Borehole Seismic (VSP)

Core

- Whole core[1]
- Mechanical Sidewall Cores (depending on core results)

Core Testing

- RCA – porosity permeability, grain density
- Tight Rock (seal, low permeability) – porosity permeability, grain density
- XRD - mineralogy
- SCAL – rel perm, cap pressure, Kv/Kh
- TCS/MCS & UCS – mechanical properties
- Fluid testing – geochemistry

[1] Seal and Reservoir formations

4.2.1 To be performed during and after casing installation

Cement evaluation and mechanical integrity

- Ultrasonic (PowerFlex), Casing Bond Log (CBL), ElectroMagnetic (EMIT) and/or Magnetic Flux Leakage (MFL)

Mechanical integrity, formation CO2 saturation monitoring

- Pulsed neutron (Pulsar) baseline

Formation reservoir and mechanical

- Perforate, Falloff test, injectivity test with production log

4.2.2 Demonstration of mechanical integrity

Below (Table 5) is a summary of the MITs and pressure fall-off tests to be performed prior to injection:

Table 5: Summary of the Mendota_INJ_1 MITs and pressure fall-off tests to be performed prior to injection

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	Pressure test	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Pressure test	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Casing inspection Ultrasonic and CBL	Prior to operation
40 CFR 146.87(e)(1)	Testing prior to operating	Pressure fall-off test	Prior to operation

CES will notify EPA least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notice and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

5. Pre-Injection Testing Plan – Deep Monitoring Well Mendota_OBS_1

5.1 Deviation Checks

Deviation measurements will be conducted at a minimum of approximately every 300 feet during construction of the well. More comprehensive deviation checks will be provided at the end of each hole section with greater granularity of 100 ft between checks with inclination and azimuth. (Note: This may be done with MWD while drilling the hole section) A gyro survey of the completed well will be done at the installation of the long string of casing for a final verification of the wellbore trajectory.

5.2 Tests and Logs

<u>*Surface section of wellbore*</u>

- Triple-combo (Density, Neutron Porosity, Resistivity, Gamma Ray, Spontaneous Potential)
- BHC Sonic

<u>*Intermediate section of wellbore*</u>

Porosity, permeability and lithology for future monitoring

- Triple-combo (Density, Neutron Porosity, Resistivity, Gamma Ray, Spontaneous Potential)
- Magnetic Resonance (CMR), Elemental Spectroscopy (LithoScanner), Spectral GR

Fractures, Geomechanics, Geophysical tie, Microseismic

- Borehole Imaging[1] (FMI)
- Dipole Sonic (Sonic Scanner – Anisotropy[1], Stoneley[1])

Pressures, permeability, fluid samples, Calibrate geomechanics/formation stress

- Formation tester (MDT)
- Dual Packer or Sleeve DFIT tests (MDT)

Core

- Whole core[1]
- Mechanical Sidewall Cores (depending on core results)

<u>*TD section of wellbore*</u>

Porosity, permeability and lithology for future monitoring

- Triple-combo (Density, Neutron Porosity, Resistivity, Gamma Ray, Spontaneous Potential)
- Magnetic Resonance (CMR), Elemental Spectroscopy (LithoScanner), Spectral GR

Fractures, Geomechanics, Geophysical tie, Microseismic

- Borehole Imaging[1] (FMI)
- Dipole Sonic (Sonic Scanner – Anisotropy[1], Stoneley[1])

Pressures, permeability, fluid samples, Calibrate geomechanics/formation stress

- Formation tester (MDT)
- Dual Packer or Sleeve DFIT tests (MDT)

Geophysical

- Borehole Seismic (VSP)

Core

- Whole core[1]
- Mechanical Sidewall Cores (depending on core results)

Core Testing

- RCA – porosity permeability, grain density
- Tight Rock (seal, low permeability) – porosity permeability, grain density
- XRD - mineralogy
- SCAL – rel perm, cap pressure, Kv/Kh
- TCS/MCS & UCS – mechanical properties
- Fluid testing – geochemistry

[1] Seal and Reservoir formations

5.2.1 To be performed during and after casing installation

Cement evaluation and mechanical integrity

- Ultrasonic (PowerFlex), Casing Bond Log (CBL). ElectroMagnetic Thickness (EMIT), Magnetic Flux Leakage (MFL)

Mechanical integrity, formation CO2 saturation monitoring

- Pulsed neutron (Pulsar) baseline

5.2.2 Demonstration of mechanical integrity

Below (Table 6) is a summary of the MITs to be performed on the deep monitoring well(s), Mendota_OBS_1 and Mendota_ACZ_1, after installation and prior to commencing CO_2 injection operations:

Table 6: MITs to be performed on the deep monitoring well(s), Mendota_OBS_1 and Mendota_ACZ_1

Rule Description	Test Description	Program Period
MIT - Internal	Pressure test	Prior to operation
MIT - External	Pressure test	Prior to operation
MIT - External	Casing inspection, EMIT, MFL, Ultrasonic and CBL	Prior to operation
Testing prior to operating	Pressure fall-off test	Prior to operation

Notice and the opportunity to witness the test/log shall be provided to EPA at least 48 hours in advance of a given test/log.

6. Annulus Pressure Test Procedures for Injection Well (Mendota_INJ_1): Test Pressure

To assure that the test pressure will detect significant leaks and that the casing is subjected to pressure similar to that which would be applied if the tubing or packer fails, the tubing/casing annulus should be tested at a pressure equal to the maximum allowed injection pressure or 1000 psig whichever is less. The annular test pressure must, however, have a difference of at least 200 psig either greater or less than the injection tubing pressure. Wells which inject at pressures of less than 300 psig must test at a minimum pressure of 300 psig, and the pressure difference between the annulus and the injection tubing must be at least 200 psi.

6.1 Test Criteria

1. The duration of the pressure test is 30 minutes.
2. Both the annulus and tubing pressures should be monitored and recorded every five (5) minutes.
3. If there is a pressure change of 10 percent or more from the initial test pressure during the 30 minute duration, the well has failed to demonstrate mechanical integrity and should be shut-in until it is repaired or plugged.
4. A pressure change of 10 percent or more is considered significant. If there is no significant pressure change in 30 minutes from the time that the pressure source is disconnected from the annulus, the test may be completed as passed.

6.2 Recordkeeping and Reporting

The test results must be recorded. The annulus pressure should be recorded at five (5) minute intervals. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded and a pressure recording chart documenting the actual annulus test pressures must be attached to the submittal. The tubing pressure at the beginning and end of each test must be recorded. The volume of the annulus fluid bled back at the surface after the test should be measured and recorded. This can be done by bleeding the annulus pressure off and discharging the associated fluid into a five gallon container. The volume information can be used to verify the approximate location of the packer.

6.3 Procedures for Pressure Test

1. Scheduling the test should be done at least two (2) weeks in advance.

2. Information on the well completion (location of the packer, location of perforations, previous cement work on the casing, size of casing and tubing, etc.) and the results of the previous MIT test should be reviewed by the field inspector in advance of the test. Regional UIC Guidance should also be reviewed. Information relating to the previous MIT and any well workovers should be reviewed and taken into the field for verification purposes.

3. Wells should be shut-in prior to the test. A 12 to 24-hour shut in is preferable to assure that the temperature of the fluid in the wellbore is stable.

4. The casing/tubing annulus should be filled with inhibited fluid at least 24 hours in advance, if possible.

5. Filling the annulus should be undertaken through one valve with the second valve open to allow air to escape. After the operator has filled the annulus, a check should be made to assure that the annulus will remain full. If the annulus cannot maintain a full column of fluid, the operator should notify the Director and begin a rework. The operator should measure and report the volume of fluid added to the annulus. If not already the case, the casing/tubing valves should be closed, at least, 24 hours prior to the pressure test.

6.4 Following steps are at Mendota_INJ_1:

1. Read tubing pressure and record on the form. If the well is shut-in, the reported information on the actual maximum operating pressure should be used to determine test pressures.
2. Read pressure on the casing/tubing annulus and record value on the form. If there is pressure on the annulus, it should be bled off prior to the test. If the pressure will not bleed-off, the guidance on well failures should be followed.
3. Ask the operator for the date of the last workover and the volume of fluid added to the annulus prior to this test and record information on the form.
4. Hook-up well to pressure source and apply pressure until test value is reached.
5. Immediately disconnect pressure source and start test time (If there has been a significant drop in pressure during the process of disconnection, the test may have to be restarted). The pressure gages used to monitor injection tubing pressure and annulus pressure should have a pressure range which will allow the test pressure to be near the mid-range of the gage. Additionally, the gage must be of sufficient accuracy and scale to allow an accurate reading of a 10 percent change to be read. For instance, a test pressure of 600 psi should be monitored with a 0 to 1000 psi gage. The scale should be incremented in 20 psi increments.
6. Record tubing and annulus pressure values every five (5) minutes.
7. At the end of the test, record the final tubing pressure.
8. If the test fails, check the valves, bull plugs and casing head close up for possible leaks. The well should be retested.
9. If the second test indicates a well failure, the Region should be informed of the failure within 24 hours by the operator, and the well should be shut-in within 48 hours. A follow-up letter should be prepared by the operator which outlines the cause of the MIT failure and proposes a potential course of action. This report should be submitted to EPA within five days.
10. Bleed off well into a bucket, if possible, to obtain a volume estimate. This should be compared to the calculated value obtained using the casing/tubing annulus volume and fluid compressibility values.
11. Return to office and prepare follow-up.

7. Annulus Pressure Test Procedures for Mendota_OBS_1:

7.1 Test Pressure

To assure that the test pressure will detect significant leaks and that the casing is subjected to pressure similar to that which would be applied if the tubing or packer fails, the tubing/casing annulus should be tested at a pressure equal to the maximum allowed injection pressure or 1000 psig whichever is less. The annular test pressure must, however, have a difference of at least 200 psig either greater or less than the injection tubing pressure. Wells which inject at pressures of less than 300 psig must test at a minimum pressure of 300 psig, and the pressure difference between the annulus and the injection tubing must be at least 200 psi.

7.2 Test Criteria

1. The duration of the pressure test is 30 minutes.
2. Both the annulus and tubing pressures should be monitored and recorded every five (5) minutes.
3. If there is a pressure change of 10 percent or more from the initial test pressure during the 30-minute duration, the well has failed to demonstrate mechanical integrity and should be shut-in until it is repaired or plugged.
4. A pressure changes of 10 percent or more is considered significant. If there is no significant pressure change in 30 minutes from the time that the pressure source is disconnected from the annulus, the test may be completed as passed.

7.3 Recordkeeping and Reporting

The test results must be recorded. The annulus pressure should be recorded at five (5) minute intervals. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded and a pressure recording chart documenting the actual annulus test pressures must be attached to the submittal. The tubing pressure at the beginning and end of each test must be recorded. The volume of the annulus fluid bled back at the surface after the test should be measured and recorded. This can be done by bleeding the annulus pressure off and discharging the associated fluid into a five gallon container. The volume information can be used to verify the approximate location of the packer.

7.4 Procedures for Pressure Test

1. Scheduling the test should be done at least two (2) weeks in advance.
2. Information on the well completion (location of the packer, location of perforations, previous cement work on the casing, size of casing and tubing, etc.) and the results of the previous MIT test should be reviewed by the field inspector in advance of the test. Regional UIC Guidance should also be reviewed. Information relating to the previous MIT and any well workovers should be reviewed and taken into the field for verification purposes.
3. Wells should be shut-in prior to the test. A 12 to 24-hour shut in is preferable to assure that the temperature of the fluid in the wellbore is stable.
4. The casing/tubing annulus should be filled with inhibited fluid at least 24 hours in advance, if possible.
5. Filling the annulus should be undertaken through one valve with the second valve open to allow air to escape. After the operator has filled the annulus, a check should be made to assure that the annulus will remain full. If the annulus cannot maintain a full column of

fluid, the operator should notify the Director and begin a rework. The operator should measure and report the volume of fluid added to the annulus. If not already the case, the casing/tubing valves should be closed, at least, 24 hours prior to the pressure test.

7.5 Following steps are at the well:

1. Read tubing pressure and record on the form. If the well is shut-in, the reported information on the actual maximum operating pressure should be used to determine test pressures.
2. Read pressure on the casing/tubing annulus and record value on the form. If there is pressure on the annulus, it should be bled off prior to the test. If the pressure will not bleed-off, the guidance on well failures should be followed.
3. Ask the operator for the date of the last workover and the volume of fluid added to the annulus prior to this test and record information on the form.
4. Hook-up well to pressure source and apply pressure until test value is reached.
5. Immediately disconnect pressure source and start test time (If there has been a significant drop in pressure during the process of disconnection, the test may have to be restarted). The pressure gages used to monitor injection tubing pressure and annulus pressure should have a pressure range which will allow the test pressure to be near the mid-range of the gage. Additionally, the gage must be of sufficient accuracy and scale to allow an accurate reading of a 10 percent change to be read. For instance, a test pressure of 600 psi should be monitored with a 0 to 1000 psi gage. The scale should be incremented in 20 psi increments.
6. Record tubing and annulus pressure values every five (5) minutes.
7. At the end of the test, record the final tubing pressure.
8. If the test fails, check the valves, bull plugs and casing head close up for possible leaks. The well should be retested.
9. If the second test indicates a well failure, the Region should be informed of the failure within 24 hours by the operator, and the well should be shut-in within 48 hours. A follow-up letter should be prepared by the operator which outlines the cause of the MIT failure and proposes a potential course of action. This report should be submitted to EPA within five days.
10. Bleed off well into a bucket, if possible, to obtain a volume estimate. This should be compared to the calculated value obtained using the casing/tubing annulus volume and fluid compressibility values.
11. Return to office and prepare follow-up.

8. Pressure Fall-Off Test Procedures:

8.1 Purpose

The purpose of this test is to identify injection interval or wellbore problems and injection interval characteristics. It is the responsibility of the permittee to develop a testing procedure which will generate adequate data for a meaningful analysis.

8.2 Regulatory Citation

The Class VI Rule requires monitoring of the pressure buildup in the injection zone at least every five (5) years and more frequently if required by the UIC program director [40 CFR 146.90(f), including at a minimum, shut down of the well for a time sufficient to conduct a valid observation of the pressure falloff. This test is known as the formation pressure fall-off test.

8.3 Timing of Fall Off Tests and Submission

Falloff tests must be conducted within one year from the date of the original petition approval and annually thereafter. The time interval for each test should not be less than 9 months or greater than 15 months from the previous test. This will ensure that the tests will be performed at relatively even intervals throughout the duration of the petition approval period. Operators can, at their discretion, plan these tests to coincide with the performance of their annual state MIT requirements as long as the time requirements are met. The falloff testing report should be submitted no later than 60 days following the test. Failure to submit a falloff test report will be considered a violation of the applicable petition condition and may result in an enforcement action. Any exceptions should be approved by EPA prior to conducting the test.

8.4 Fall Off Test Report Requirements

In general, the report to EPA should provide general information and an overview of the falloff test, an analysis of the pressure data obtained during the test, a summary of the test results, and a comparison of the results with the parameters used in the no migration demonstration. Some of the following operator and well data will not change so once acquired, it can be copied and submitted with each annual report. The falloff test report should include the following information:

1. Company name and address
2. Test well name and location
3. The name and phone number of the facility contact person. The contractor contact may be included if approved by the facility in addition to a facility contact person.
4. A photocopy of an openhole log (SP or Gamma Ray) through the injection interval illustrating the type of formation and thickness of the injection interval. The entire log is not necessary.
5. Well schematic showing the current wellbore configuration and completion information:
    - Wellbore radius
    - Completed interval depths
    - Type of completion (perforated, screen and gravel packed, openhole)
6. Depth of fill depth and date tagged.
7. Offset well information:
    - Distance between the test well and offset well(s) completed in the same interval or involved in an interference test
    - Simple illustration of locations of the injection and offset wells
8. Chronological listing of daily testing activities.
9. Electronic submission of the raw data (time, pressure, and temperature) from all pressure gauges utilized on a floppy disk or CD-ROM. A READ.ME file or the disk label should list all files included and any necessary explanations of the data. A separate file containing any edited data used in the analysis can be submitted as an additional file.
10. Tabular summary of the injection rate or rates preceding the falloff test. At a minimum, rate information for 48 hours prior to the falloff or for a time equal to twice the time of the falloff test is recommended. If the rates varied and the rate information is greater than 10 entries, the rate data should be submitted electronically as well as a hard copy of the

rates for the report. Including a rate vs time plot is also a good way to illustrate the magnitude and number of rate changes prior to the falloff test.

11. Rate information from any offset wells completed in the same interval. At a minimum, the injection rate data for the 48 hours preceding the falloff test should be included in a tabular and electronic format. Adding a rate vs time plot is also helpful to illustrate the rate changes.
12. Hard copy of the time and pressure data analyzed in the report.
13. Pressure gauge information:
    - List all the gauges utilized to test the well
    - Depth of each gauge
    - Manufacturer and type of gauge. Include the full range of the gauge.
    - Resolution and accuracy of the gauge as a % of full range.
    - Calibration certificate and manufacturer's recommended frequency of calibration
14. General test information:
    - Date of the test
    - Time synchronization: A specific time and date should be synchronized to an equivalent time in each pressure file submitted. Time synchronization should also be provided for the rate(s) of the test well and any offset wells.
    - Location of the shut-in valve (e.g., note if at the wellhead or number of feet from the wellhead)
15. Reservoir parameters (determination):
    - Formation fluid viscosity,(direct measurement or correlation)
    - Porosity, (well log correlation or core data)
    - Total compressibility, (correlations, core measurement, or well test)
    - Formation volume factor, (correlations, usually assumed 1 for water)
    - Initial formation reservoir pressure -
    - Date reservoir pressure was last stabilized (injection history)
    - Justified interval thickness,
16. Waste plume:
    - Cumulative injection volume into the completed interval
    - Calculated radial distance to the waste front
    - Average historical waste fluid viscosity, if used in the analysis
17. Injection period:
    - Time of injection period
    - Type of test fluid
    - Type of pump used for the test (e.g., plant or pump truck)
    - Type of rate meter used
    - Final injection pressure and temperature
18. Falloff period:
    - Total shut-in time, expressed in real time and elapsed time
    - Final shut-in pressure and temperature
    - Time well went on vacuum, if applicable
19. Pressure gradient:
    - Gradient stops - for depth correction

20. Calculated test data: include all equations used and the parameter values assigned for each variable within the report
    - Radius of investigation
    - Slope or slopes from the semilog plot
    - Transmissibility
    - Permeability
    - Calculation of skin
    - Calculation of skin pressure drop
    - Discussion and justification of any reservoir or outer boundary models used to simulate the test
    - Explanation for any pressure or temperature anomaly if observed
21. Graphs:
    - Cartesian plot: pressure and temperature vs. time
    - Log-log diagnostic plot: pressure and semilog derivative curves. Radial flow regime should be identified on the plot
    - Semilog and expanded semilog plots: radial flow regime indicated and the semilog straight line drawn
    - Injection rate(s) vs time: test well and offset wells (not a circular or strip chart)
22. A comparison of all parameters with those used in the petition demonstration, including references where the parameters can be found in the petition.
23. A copy of the latest radioactive tracer run to fulfill the annual mechanical integrity testing requirement for the State and a brief discussion of the results.
24. Compliance with any unusual petition approval conditions such as the submission of an annual flow profile survey. These additional conditions may be addressed either in the annual falloff testing report or in an accompanying document.

8.5 Planning

The radial flow portion of the test is the basis for all pressure transient calculations. Therefore,the injectivity and falloff portions of the test should be designed not only to reach radial flow, but to sustain a time frame sufficient for analysis of the radial flow period.

General Operational Concerns

Successful well testing involves the consideration of many factors, most of which are within the operator's control. Some considerations in the planning of a test include:

- Adequate storage for the waste should be ensured for the duration of the test
- Offset wells completed in the same formation as the test well should be shut-in, or at a minimum, provisions should be made to maintain a constant injection rate prior to and during the test
- Install a crown valve on the well prior to starting the test so the well does not have to be shut-in to install a pressure gauge
- The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period
- The condition of the well, junk in the hole, wellbore fill or the degree of wellbore damage (as measured by skin) may impact the length of time the well must be shut-in for a valid

falloff test. This is especially critical for wells completed in relatively low transmissibility reservoirs or wells that have large skin factors.

- Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well
- Accurate recordkeeping of injection rates is critical including a mechanism to synchronize times reported for injection rate and pressure data. The elapsed time format usually reported for pressure data does not allow an easy synchronization with real time rate information. Time synchronization of the data is especially critical when the analysis includes the consideration of injection from more than one well.
- Any unorthodox testing procedure, or any testing of a well with known or anticipated problems, should be discussed with EPA staff prior to performing the test.
- Other pressure transient tests may be used in conjunction or in place of a falloff test in some situations. For example, if surface pressure measurements must be used because of a corrosive wastestream and the well will go on vacuum following shut-in, a multi-rate test may be used so that a positive surface pressure is maintained at the well.
- If more than one well is completed into the same reservoir, operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well following the falloff test. These pulses will demonstrate communication between the wells and, if maintained for sufficient duration, they can be analyzed as an interference test to obtain interwell reservoir parameters.

8.6 Pretest Planning

1. Determine the time needed to reach radial flow during the injectivity and falloff portions of the test:
    - Review previous well tests, if available
    - Simulate the test using measured or estimated reservoir and well completion parameters
    - Calculate the time to the beginning of radial flow using the empirically-based equations provided in the Appendix. The equations are different for the injectivity and falloff portions of the test with the skin factor influencing the falloff more than the injection period. (See Appendix, page A-4 for equations)
    - Allow adequate time beyond the beginning of radial flow to observe radial flow so that a well-developed semi log straight line occurs. A good rule of thumb is 3 to 5 times the time to reach radial flow to provide adequate radial flow data for analysis.
2. Adequate and consistent injection fluid should be available so that the injection rate into the test well can be held constant prior to the falloff. This rate should be high enough to produce a measurable falloff at the test well given the resolution of the pressure gauge selected. The properties of the fluid should be consistent. Any mobility issues should be identified and addressed in the analysis if necessary.
3. Bottomhole pressure measurements are usually superior to surface pressure measurements because bottomhole measurements tend to be less noisy. Surface pressure measurements can be used if positive pressure is maintained at the surface throughout the falloff portion of the test. The surface pressure gauge should be located at the wellhead. A surface pressure gauge may also serve as a backup to a downhole gauge and provide a monitoring tool for tracking the test progress. Surface gauge data can be plotted during

the falloff in a log-log plot format with the pressure derivative function to determine if the test has reached radial flow and can be terminated. Note: Surface pressure measurements are not adequate if the well goes on a vacuum during the test. (See Appendix, page A-2 for additional information concerning pressure gauge selection.)

4. Use two pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality. The two gauges do not need to be the same type. (See Appendix, page A-1 for additional information concerning pressure gauges.)

8.7 Conducting the Fall Off Test

1. Tag and record the depth to any fill in the test well
2. Simplify the pressure transients in the reservoir
    - Maintain a constant injection rate in the test well prior to shut-in. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.
    - Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
    - Do not shut-in two wells simultaneously or change the rate in an offset well during the test.
3. The well must be shut-in at the wellhead or as near to the wellhead as feasible in order to minimize wellbore storage and after flow. The shut-in must be accomplished as instantaneously as possible to prevent erratic pressure behavior during the test.
4. Maintain accurate rate records for the test well and any offset wells completed in the same injection interval.
5. Measure and record the properties of the injectate periodically during the injectivity portion of the test to confirm the consistency of the test fluid.
6. The surface readout downhole pressure gauge must be located at or near the top of the injection interval, unless previous testing indicates a more appropriate location. A surface readout should be provided to allow flexibility in determining appropriate pressure measuring and recording time intervals and to ensure valid test data is generated and false testing runs can be identified and aborted.
7. The injection rate and injection liquid density for the test must be held constant prior to shut-in.
8. The injection rate must be high enough and continuous for a period of time sufficient to produce a pressure buildup that will result in valid test data.
9. The injection rate must result in a pressure buildup such that a semi log straight line can be determined from the Horner plot. The injection rate should be the maximum injection rate that can be feasibly maintained constant in order to maximize pressure changes in the formation and provide valid test results, but not exceeding the daily injection volume limit of the UIC Permit.
10. If the stabilization injection period is interrupted, for any reason and for any length of time, the stabilization injection period must be restarted.
11. The fall-off portion of the test must be conducted for a length of time sufficient such that the pressure is no longer influenced by wellbore storage or skin effects and enough data points lie within the infinite acting period and the semi log straight line is well developed.

8.8 Evaluation of the Test Results

A licensed geologist or licensed professional engineer, licensed by the Board for Professional Engineers, Land Surveyors, and Geologists to practice geology or engineering in California and knowledgeable in the methods of pressure transient test analysis, must evaluate the test results.

1. The following information and evaluations must be provided with the test report:
    - Prepare a Cartesian plot of the pressure and temperature versus real time or elapsed time.
    - Confirm pressure stabilization prior to shut-in of the test well
2. Look for anomalous data, pressure drop at the end of the test, determine if pressure drop is within the gauge resolution
3. Prepare a log-log diagnostic plot of the pressure and semi log derivative. Identify the flow
    - regimes present in the well test
    - Use the appropriate time function depending on the length of the injection period and variation in the injection rate preceding the falloff
    - Mark the various flow regimes - particularly the radial flow period
    - Include the derivative of other plots, if appropriate (e.g., square root of time for linear flow)
    - If there is no radial flow period, attempt to type curve match the data
4. Prepare a semi log plot.
    - Use the appropriate time function depending on the length of injection period and injection rate preceding the falloff
    - Draw the semi log straight line through the radial flow portion of the plot and obtain the slope of the line
    - Calculate the transmissibility
    - Calculate the skin factor and skin pressure drop
    - Calculate the radius of investigation
5. Explain any anomalous data responses. The analyst should investigate physical causes other than reservoir responses.
6. All equations used in the analysis must be provided with the appropriate parameters substituted in them.

Note: Tests conducted in relatively transmissive reservoirs are more sensitive to the temperature compensation mechanism of the gauge, because the pressure buildup response evaluated is smaller. For this reason, the plot of the temperature data should be reviewed. Any temperature anomalies should be noted to determine if they correspond to pressure anomalies.

Compliance with any unusual petition approval conditions such as the submission of an annual flow profile survey. These additional conditions may be addressed either in the annual falloff testing report or in an accompanying document.

8.9 Comparison of Fall Off results to no migration petition data

A comparison between the falloff test results and the parameters used in the no migration petition demonstration should be made. Specifically, the following should be demonstrated:

- Both the flowing and static bottom hole pressures measured during the test should be corrected for skin and be at or below those which were predicted to occur by the pressure buildup model in the provided no migration petition for the same point in time.
- It should be shown that the (kh/*) parameter group calculated from the current falloff data is the same or greater than that employed in the pressure buildup modeling

9. References

Schlumberger Quality Assurance and Surveillance Plan. (2020). *Quality Assurance and Surveillance Plan.*

Schlumberger, Attachment A: Summary of Requirements Class VI Operating. (2020). *Attachment A: Summary of Requirements Class VI Operating and Reporting Conditions.*

Schlumberger, Attachment B: Area of Review and Corrective Action Plan. (2020). *Attachment B: Area of Review and Corrective Action Plan 40 CFR 146.84(b) Clean Energy Systems Mendota.*

Schlumberger, Attachment C: Testing and Monitoring Plan. (2020). *Attachment C: Testing and Monitoring Plan 40 CFR 146.90 Clean Energy Systems Mendota.*

Schlumberger, Attachment D: Injection Well Plugging Plan. (2020). *Attachment D: Injection Well Plugging Plan 40 CFR 146.92(B) Clean Energy Systems Mendota.*

Schlumberger, Attachment E: Post-Injection Site Care and Site Closure Plan. (2020). *Attachment E: Post-Injection Site Care and Site Closure Plan 40 CFR 146.93(A) Clean Energy Systems Mendota.*

Schlumberger, Attachment F: Emergency and Remedial Response Plan. (2020). *Attachment F: Emergency and Remedial Response Plan 40 CFR 146.94(A) Clean energy Systems Mendota.*

Schlumberger, Attachment G: Construction Details Clean Energy Systems Mendota. (2020). *Attachment G: Construction Details Clean Energy Systems Mendota.*

Schlumberger, Attachment H: Financial Assurance Demonstration. (2020). *Attachment H: Financial Assurance Demonstration 40 CFR 146.85 Clean Energy Systems Mendota.*

Schlumberger, Class VI Permit Application Narrative. (2020). *Class VI Permit Application Narrative 40 CFR 146.82(A) Clean Energy Systems Mendota.*